CHAPTER

4

Barriers That Impede Widespread Adoption of Distributed Generation

Advocates of distributed generation contend that many industry practices and government restrictions discourage investment in and beneficial operation of customer-owned generators that could, without adverse effects, lower the costs of electricity for all customers. Opponents argue that such practices and restrictions are necessary to protect utilities and general ratepayers from increased costs, to maintain the reliability of the electric system, and to protect the environment. Four areas of contention are frequently mentioned:

- Requirements and charges for the installation of protective equipment as a precondition to interconnection with the grid;
- Surcharges on the electricity bills of operators of distributed generators (those who remain utility customers);
- Prices established for the distributed power that utilities purchase; and
- Environmental siting restrictions and permitting requirements.

Proponents of wider adoption say that well-crafted reforms in those areas would benefit not only customers who adopted distributed generation but also electricity customers as a group. Critics argue that such reforms would shift the burden of paying for the fixed costs of the electricity supply network from owners of distributed generation to other ratepayers. Distributed generators would continue to benefit from the network—as a source of supplemental power, for example—without paying their fair share of those fixed costs.

Protecting the Grid: Interconnection Requirements and Costs

The most commonly cited category of industry practices that proponents of distributed generation claim presents a barrier to adoption comprises the technical restrictions, contractual requirements, and associated costs for connecting customer-owned generators to the grid. Proponents claim that, for many types of distributed generation, the requirements are often excessive and time-consuming, resulting in additional unwarranted costs and significant project delays.

The stated purpose of the technical interconnection restrictions and requirements is to ensure the safety and quality of the electric power system and to avoid possible damage to equipment. Those restrictions often prohibit small generators from connecting to the grid at the distribution level of the network. For example, under existing rules in some utilities' service territories, customers with on-site generation must disconnect completely from the grid before starting their generators, to protect against accidental transmission of power onto the grid or possible voltage and frequency disturbances from the new power.

In the absence of outright prohibitions, however, operators of distributed generation units may want to remain connected to the grid while producing power (termed parallel operation)—whether to draw supplemental power from the grid or to transmit excess power onto it. In that case, utilities generally require operators to install additional controls and equipment in order to protect the network from feedbacks or disturbances. That additional site-specific equipment may include voltage regulators, frequency synchronizers, isolation devices, monitoring devices, and network protectors. Because the number and types of devices that utilities require vary widely and depend on many factors, utilities often demand specialized studies—typically paid for by the operator—to determine the equipment necessary in each case. Utilities may also require upgrades to the distribution system itself to support the power supplied by the distributed generators and to protect neighboring customers from disruptions or variations in power quality. Operators typically bear the cost of such site-specific equipment and any system upgrades, too.

In general, utilities require that operators of distributed generators execute contracts governing the interconnection of their equipment with the distribution and transmission network. Distributed generation proponents complain that provisions in those contracts are often one-sided or overly burdensome. They include insurance requirements that may boost operators' costs significantly and indemnification and dispute-resolution provisions that proponents say unfairly favor the utilities.

Many observers argue that those technical and contractual interconnection requirements are often excessive. For example, the electronic control equipment built into most small generators effectively protects against electricity feedbacks and other technical problems, so industry requirements for additional equipment are often redundant. A recent study from the National Renewable Energy Laboratory (NREL) documented several cases in which utilities insisted on separate equipment when generators already had such protection.[1] Similarly, specialized interconnection studies may be unnecessary for broad classes of generating equipment and operating conditions. Such studies not only add costs but also can delay the start-up of distributed generation projects. For the operators of small-scale distributed generators—especially in residential or small commercial settings—those costs can represent a sizable part of the total cost of interconnecting with the grid, and in many cases they are steep enough to jeopardize the economic viability of using distributed generation in those applications.

The NREL study documented numerous instances in which developers of distributed generation projects faced interconnection costs that they viewed as "above normal." In 12 out of 42 projects, developers cited excessive technical costs. Another six projects were abandoned because of barriers. The "above normal" costs ranged from $20 per kilowatt to more than $1,000 per kilowatt. Smaller projects tended to face higher per-kilowatt interconnection costs because some of those charges do not vary depending on the size of the generator.

Utility Surcharges: Paying for Stranded Costs and Standby Service

Under the electric utility regulations in most states, utilities may levy surcharges on customers who install distributed generators and operate them regularly. Typically, the surcharges take the form of flat monthly charges based on customers' past maximum usage. Monthly charges may be used to help utilities cover the costs of public benefits programs (such as purchasing renewable power or providing service to remote customers). Regulators in every state require utilities to conduct such programs, which are otherwise financed by electricity sales. More commonly, however, monthly charges are used to pay for past capital investments and for standby service.

Helping utilities recover some portion of their past capital investments is part of the purpose behind those monthly charges. Normally, a utility makes a capital investment (for example, to build a new generation plant) and then sets electricity rates at a level that will ensure recovery of those costs over time. But if electricity sales are lower than the utility expected—perhaps because rules change to allow some customers to generate power themselves—the utility's rates will not be sufficient to

1. Department of Energy, National Renewable Energy Laboratory, *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*, NREL/SR-200-28053 (May 2000).

pay off the investment. Revenues from so-called exit fees (surcharges imposed on customers who shift from full service to backup service) can help make up that deficit. Proponents of distributed power argue that the unrecoverable (or "stranded") costs covered by exit fees often do not reflect the actual costs of past investments, which have become uneconomic with the drop in customer demand.[2]

The more common purpose of the recurring monthly charge that some utilities impose on operators of distributed generators is to pay the utility's cost of maintaining standby generating capacity and distribution lines to serve that household or business. As retail utility customers, operators are able to purchase electricity whenever their on-site generators experience an outage (for whatever reason), and the utility must provide service to them. For example, Pacific Gas and Electric Company charges $2.55 per kilowatt per month for standby service to customers "who require PG&E to provide reserve capacity and stand ready at all times to supply electricity on an irregular or noncontinuous basis."[3] If those surcharges exceed the cost to the utility of providing standby service, they will discourage the efficient siting of distributed generators.

For nonresidential customers, the charge for standby service is often based on the maximum amount of electricity that the business draws from the grid in a short interval, such as 15 minutes. That maximum is often determined by the customer's past consumption. If a customer had drawn electricity at a maximum rate of 50 kilowatts for 15 minutes in the past three years, for instance, then that kilowatt level would be used to set the monthly charge. The utility would charge, say, $2 per month per kilowatt, or a total of $100 per month, for that customer's standby service. For a typical customer, the charge would amount to roughly one-half cent per kilowatt-hour.

2. For a discussion, see Congressional Budget Office, *Electric Utilities: Deregulation and Stranded Costs* (October 1998).

3. That charge is equivalent to approximately 35 cents per kilowatt-hour per month for customers who operate their equipment continuously.

Proponents of distributed generation argue that standby charges often overstate the cost of the service provided by the retail utility and fail to account for the benefits that distributed generators provide to the system. Because the probability of broad unscheduled outages by distributed generators is slight, the extra capacity needed to serve those customers is only a small fraction of the standby service (the maximum potential draw on the system) for which they are charged. Utilities can benefit from distributed generation by deferring some spending on transmission and distribution upgrades that would otherwise be needed to serve new customers. In general, however, such benefits are not subtracted from customers' monthly charges.

The Public Utility Regulatory Policy Act (PURPA) specifically requires utilities to provide standby service for cogenerators and others that use certain renewable fuels at nondiscriminatory rates. But many utilities only have pro forma tariffs for standby service, and they set the actual rates on a case-by-case basis.[4] As a result, rates vary widely; in many cases, they can significantly increase the costs of distributed generation projects. The NREL study on barriers to adoption of distributed generation documented charges for standby service that ranged from less than zero (a credit) to more than $18.75 per kilowatt per month. In New York, charges for standby service range from $4 to $16 per kilowatt per month. For the average residential customer or small commercial enterprise that may draw a maximum of only about 2 kilowatts, a monthly charge at the high end of those ranges could boost its electricity bills by as much as 20 percent. The NREL noted that such wide variations "demonstrate a lack of consistency and an absence of regulatory oversight of [standby] tariffs." According to the study, "the lack of appropriate regulatory principles or standards . . . creates uncertainty" that increases the financial risk for distributed power projects.[5]

4. A pro forma tariff contains general language authorizing the utility to charge for a service on the basis of defined conditions and cost categories. The actual price is determined on a case-by-case basis, consistent with the conditions stated in the tariff.

5. Department of Energy, National Renewable Energy Laboratory, *Making Connections*, pp. 21 and 24.

Compensating for Avoided Costs: Prices for Power Sold to Utilities

A third category of barriers identified by proponents of distributed generation is the price operators receive for selling their excess electricity to the utilities. To date, markets for excess power from small distributed generators are underdeveloped in many areas of the country. In those areas, there are no standardized rules that allow most operators to sell electricity onto the power grid, and no generally accepted mechanism is in place to set the prices for such sales. In some cases, federal and state rules have mandated that utilities purchase power from certain distributed generators, but the administratively set prices for that output generally do not induce producers to operate efficiently.

PURPA requires utilities to purchase electricity from independent generators that use cogeneration or various renewable energy technologies at prices based on the utilities' wholesale cost of power (their "avoided cost"). In the past, utilities have often determined their avoided costs on the basis of the least expensive alternative source of power, regardless of when it was generated. Independent power producers have complained that those prices are unreasonably low. Utilities frequently fail to provide credits for reducing costs during peak periods of consumption and for deferring upgrades to transmission and distribution networks.

Another way that certain operators receive credit for power they supply to the grid is through net metering. As of 2001, 33 states had mandated some type of net-metering through legislation or regulation.[6] Under a typical net-metering tariff, a customer's electricity meter is allowed to run backwards when it supplies power, reducing the customer's net consumption. This device effectively provides a credit for the generated power at the retail electricity rate, up to the point at which the customer generates more power than he or she consumes in a billing period. Some states require utilities to purchase power beyond that point at avoided costs, whereas other states do not require any additional compensation for customers. Most states with net-metering tariffs limit eligibility to small generators (typically, maximum sizes range from 10 kilowatts to 100 kilowatts) using renewable and high-efficiency technologies.

PURPA-mandated purchases and net-metering tariffs create the only organized markets for the sale of excess power from most operators of small distributed generators in the United States today. For operators who do not qualify for those markets (because their generators use conventional technologies such as internal combustion engines), often no outlet exists through which they can sell excess power. Such outlets may develop in the future, along with the establishment of wholesale power markets that compete in each region. Until they do, however, customers considering distributed generation must assess its financial attractiveness without the option of selling excess power. That limitation will constrain customers to considering generators that serve only their needs, even though larger-capacity generators could be more cost-effective, both for the customer and for all ratepayers.

For operators who do qualify to sell their excess power to the utilities, the prices they receive may not offer sufficient incentives to install and operate their distributed generators in a cost-effective manner. That is because the prices in those markets generally do not reflect the costs of the additional utility-supplied power that would have been produced in the absence of power from the distributed generators. At the wholesale level, the costs of producing and delivering electricity vary continuously by time and location, as consumption fluctuates in real time. During periods of peak demand, the cost of electricity typically rises as less-efficient generators are placed in service. The costs also vary by location because of constraints in the capacity of the transmission and distribution system that affect deliveries during periods of peak demand.

But at the retail level, prices generally do not vary by time or location.[7] Similarly, administratively set "avoided cost" payments to qualifying operators of distributed generators are often fixed, with predetermined prices in

6. For a summary of state net metering programs through May 2001, see www.awea.org/policy/netmeter.html.

7. Many retail customers are billed under time-of-use tariffs, which charge fixed prices only during predefined periods.

defined periods. Whether the cost of power is high or low during a given period, retail customers typically pay the same price per kilowatt-hour for electricity, and net-metered customers receive the same credit per kilowatt-hour. Under cost-of-service regulated rates, that price may include charges for past investments that have little relation to the cost of additional power.

That disparity between the wholesale cost of electricity and the prices that operators of distributed generators receive may raise the overall cost of electricity by limiting operators' incentives to run their units most efficiently. Distributed generators may operate during periods when it is less expensive to supply additional power from the grid, or they may remain idle when they could be producing electricity at a cost lower than that of additional grid-supplied power. In the long run, customers might install distributed generators even though the long-run marginal costs of grid-supplied power would be lower (a situation known as uneconomic bypass), or they might decide not to install generators even though the costs of distributed power would be lower.

Environmental Concerns: Siting Restrictions and Permitting Requirements

Almost all states, counties, and cities regulate the installation and operation of electricity generators. Those regulations, which vary widely across the country, are often enforced by multiple, and sometimes overlapping, jurisdictions.[8] Some analysts argue that the lack of standardized environmental regulations for distributed generation inappropriately hinders its development by making it impossible for national manufacturers to design equipment to meet a set of clear, uniform requirements. They also contend that most air quality programs fail to recognize the environmental benefits of distributed generation in reducing emissions from other sources that may be less efficient, including central power plants and customer-owned boilers. An NREL study of environmental regulations surrounding distributed generation recommended that "air quality permitting should provide credit for avoided or displaced emissions" from distributed generation.[9]

Air quality issues are one component of the permitting process for installing distributed generators. The other components are land-use approvals and building codes. Local governments require land-use approvals to ensure that a project conforms to zoning ordinances governing allowable uses for a property. Typically, ordinances do not identify electricity generating plants as a permissible land use, so jurisdictions usually require a review to weigh benefits and drawbacks and determine whether a permit should be granted. In some states, the land-use review may trigger an environmental impact review if the project might be detrimental to air and water quality, for example.

The building permit process—a separate requirement —ensures that a project conforms to certain safety standards. Those standards are described in building codes governing such characteristics as fire protection, plumbing, electric power, and mechanical equipment. Building permits are required for all new construction and most substantial building improvements and equipment additions. Building codes usually require that developers submit plans for review and approval before installation. In the case of distributed generation, building code departments may require additional information if the equipment has not been certified by an independent testing organization, such as Underwriters Laboratories.

Many building codes include specific regulations for on-site generators. Codes often require that certain building classifications be equipped with an emergency power supply to generate electricity when normal service is interrupted. Those generators must typically be powered by a fuel supply that is on the premises, such as diesel fuel or gasoline. That requirement can preclude the use of distributed generation technologies fueled by natural gas (which must be piped in), even though they can be less

8. For a detailed discussion of environmental issues surrounding the siting of distributed generation, see California Energy Commission, *Distributed Generation: CEQA Review and Permit Streamlining*, Report No. P700-00-019 (December 2000).

9. Department of Energy, National Renewable Energy Laboratory, *The Impact of Air Quality Regulations on Distributed Generation*, NREL/SR-200-31772 (October 2002).

costly to operate and are associated with fewer harmful emissions than diesel fuel or gasoline. For buildings that are required to have an emergency power supply, natural gas could be used only if the operator installed a dual-fuel generator—burning natural gas for nonemergency power needs (and sales to utilities) and burning diesel or gasoline for backup power.

State air control agencies and regional air quality management districts usually oversee the permit process for emissions. Regulations vary widely, although most districts restrict diesel-fueled backup generators to no more than 200 hours per year of operation, and only under emergency conditions. In areas that are out of compliance with air quality standards, nonexempt (large) generators must use the "best available control technology" to limit emissions and may be required to purchase rights to emit nitrogen oxides. Those requirements represent a barrier to the adoption of distributed generation because they can substantially increase the installed capital and effective operating costs of conventional internal combustion generators.

Although building standards and regulations on land use and air quality are designed to protect against significant environmental risks, some observers argue that the existing regulations governing distributed generation are often too broad or are inconsistent from site to site. The NREL study on environmental regulations and distributed generation concluded that "the complex, case-by-case permitting process designed for 'large' generators is inherently incongruous with application to small, standardized distributed generation technologies." Examples of such regulations include blanket prohibitions on electricity generation, limits on operation of backup generators, and height restrictions on towers needed for wind generators. The applicant bears the burden of obtaining an exception to those regulations, increasing the cost and time needed for approval. At a minimum, the regulations increase the uncertainty on the part of prospective owners and operators about the costs of adoption for all technologies.

Future Competitiveness: Uncertainty Surrounding Costs

With the elimination of arbitrary barriers, the market circumstances in which distributed generation technologies can compete favorably with centrally generated power, supplied by utilities, are likely to expand. But even so, the costs of power from new large generators, favored by utilities and independent producers, will probably be lower than those of distributed generation technologies in most applications. The costs of utility-supplied power are not likely to remain constant either, especially if further advances in wholesale competition or moves toward retail competition take place. The future prospects for distributed generation will depend greatly on just how the costs of utility-supplied power change. If current constraints on electricity transmission are eased or the marginal costs of producing and delivering power from central generators decline, the attractiveness of investing in distributed generation will probably diminish. It is also possible that some forms of distributed generation—especially in small-scale applications—may not fare as well as others. The bottom line is that today's investors in distributed generation technologies must be concerned not only about current barriers but also about uncertainty regarding the technologies' future competitiveness.